Entergy

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June 8, 2004

U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, D.C. 20555

SUBJECT Entergy Nuclear Operations, Inc.
Pilgrim Nuclear Power Station
Docket No. 50-293
License No. DPR-50

Licensee Event Report 1999-008-01

LETTER NUMBER 2.04.043

Dear Sir:

The enclosed supplemental Licensee Event Report (LER) 1999-008-01, "Automatic Scram at 100 Percent Power Due to Turbine Trip," is submitted in accordance with 10 CFR 50.73.

This letter contains no commitments.

Please contact Bryan Ford at (508) 830-8403 if there are any questions regarding this report.

Sincerely,

Michael A. Balduzzi

Michael A. Balduzzi

MJG/dm

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INPO Records

IE22

NRC Form 366	U.S. NUCLEAR REGULATORY COMMISSION
LICENSEE EVENT REPORT (LER) (See reverse for number of digits/characters for each block)	Estimated burden per response to comply with this mandatory information collection request: 50 hrs. Reported lessons learned are incorporated into the licensing process and fed back to industry. Forward comments regarding burden estimate to the Records Management Branch (T-6 F33), U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001, and to the Paperwork Reduction Project (3150-0104), Office of Management and Budget, Washington, DC 20503. If an information collection does not display a currently valid OMB control number, the NRC may not conduct or sponsor, and a person is not required to respond to, the information collection.

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TITLE (4)

Automatic Scram at 100 Percent Power Due to Automatic Turbine Trip

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME N/A	DOCKET NUMBER 05000
08	05	1999	1999	008	01				FACILITY NAME N/A	DOCKET NUMBER 05000

OPERATING MODE (9)	N	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR: (Check one or more) (11)							
			20.2201 (b)		20.2203(a)(2)(v)		50.73(a)(2)(i)(B)		50.73(a)(2)(viii)
POWER LEVEL (10)	100		22.2203(a)(1)		20.2203(a)(3)(i)		50.73(a)(2)(ii)(B)		50.73(a)(2)(x)
			20.2203(a)(2)(i)		20.2203(a)(3)(ii)		50.73(a)(2)(iii)		73.71
			20.2203(a)(2)(ii)		20.2203(a)(4)	X	50.73(a)(2)(iv)		OTHER
			20.2203(a)(2)(iii)		50.36(c)(1)		50.73(a)(2)(v)(D)		Specify in Abstract below or in NRC Form 366A
			20.2203(a)(2)(iv)		50.36(c)(2)		50.73(a)(2)(vii)(D)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
Bryan Ford – Licensing Manager	(508) 830-8403

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO EPIX		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO EPIX

SUPPLEMENTAL REPORT EXPECTED (14)				EXPECTED SUBMISSION DATE(15)	MONTH	DAY	YEAR
	YES (If yes, complete EXPECTED SUBMISSION DATE)	X	NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines) (16)

On August 5, 1999, an automatic scram occurred while at 100 percent power. The scram resulted from a turbine trip initiated by a high water level in turbine steam moisture separator tank 'A'. Automatic responses included the brief opening of the main steam relief valves for pressure relief.

The cause of the trip was a malfunction of moisture separator drain tank 'A' drain valve controller and incorrect setting of the drain tank's dump valve controller. The root cause determined that a lack of knowledge in understanding how this type of moisture separator level controller operated existed in the Engineering and Maintenance disciplines. This lack of knowledge led to inappropriate changes to the associated calibration procedure and improper field adjustments to the controllers themselves resulting in the high water level condition.

Corrective actions taken prior to plant restart included replacement and calibration of the level controllers. Corrective actions taken after plant restart included additional training for the Instrumentation & Calibration Technicians and Engineering Support Personnel and revision to plant procedures dealing with the calibration of controllers.

The event posed no threat to public health and safety.

REASON FOR SUPPLEMENT

This supplemental report is submitted to include the Root Cause Analysis that had not been completed when the original LER was submitted.

BACKGROUND

The Pilgrim Station power conversion systems produce electrical energy through the conversion of thermal energy contained in steam supplied from the reactor, condensing the turbine exhaust steam to water, and returning the water to the reactor as feedwater. Major components of the systems include the turbine-generator, turbine steam bypass, main condenser, condensate demineralizers and pumps, and feedwater pumps and heaters.

The turbine-generator unit consists of the turbine, generator, exciter, mechanical-hydraulic controls, and required subsystems. The turbine is a tandem-compound 23 stage unit consisting of one high pressure turbine and two low pressure turbines.

The steam is first directed to the high pressure turbine. After the steam exits the high pressure turbine, the steam is directed to four moisture separators (T-102A/B/C/D). The separators are connected in parallel and function to reduce moisture content before the steam is supplied to the low pressure turbines.

Each moisture separator is equipped with a high water level switch and drain tank. A high water level condition in a moisture separator is sensed by the separator's level switch. The level switch initiates a time delay relay (approximately 10 seconds). If a high water level condition exists at the end of the time delay, the switch automatically initiates a trip signal to the turbine's master trip solenoid (MTS-1). The level switch and time delay is a turbine protective function. There is no direct indication for moisture separator level nor a direct alarm for a moisture separator high water level condition.

Water from each moisture separator is piped to the moisture separator's drain tank. The drain tanks (T-103A/B/C/D) are each equipped with two level switches, two buoyant force level transmitters, two pneumatic level controllers, and one drain valve and one dump valve that are pneumatically operated and controlled by the respective level controller. The high level (or low level) switch functions to initiate an alarm at control room front Panel C-2 if a drain tank high (or low) water level condition occurs. One transmitter and its related level controller function to control the drain tank's drain valve that directs water to the shell side of the respective 2nd point feedwater heater. The other level transmitter and its related level controller function to control the drain tank's dump valve that directs water to the main condenser if a high water level condition occurs in the drain tank. Position indication (OPEN or CLOSED) of each drain valve is provided in the control room rear Panel C-4. Similar position is provided for each dump valve at control room front Panel C-2.

Water from moisture separator tank T-102A and drain tank T-103A is controlled and directed to the train 'A' 2nd point feedwater heater via level controller LC-3001 and drain valve LV-3001. In parallel with the LC-3001/LV-3001, water from T-102A and T-103A is controlled and directed to the main condenser via level controller LC-3002 and dump valve LV-3002. Similarly, water from T-102C and T-103C is controlled and directed to the train 'A' 2nd point feedwater heater (or main condenser) via the respective level controller and drain (or dump) valve. Water from T-102B/T-103B and T-102D/T-103D is controlled and directed to the train 'B' 2nd point feedwater heater (or main condenser) via the respective level controllers and drain (or dump) valves.

The steam extracted from various turbine stages, and the water condensed from the steam, is used for feedwater heating (cascading type feedwater heaters).

The feedwater heaters are each equipped with three level switches, level transmitters, and level indicating controllers. Two of the level switches function to provide feedwater heater alarms (high or low water level) at control room panel C-2. The other level switch functions to control the valves that isolate the extraction steam to the feedwater heater (shell side). The level transmitters monitor the water level in the feedwater heater (shell side) and provide signals to the heater's level indicating controller (LIC). The LICs are electronic and are located at control room rear Panel C-4. The LICs are calibrated for automatic or manual control, and function to control the feedwater heater's pneumatically operated drain valve and dump valve.

During the 1999 refueling outage, the 8 drain valves and dump valves of the moisture separators' drain tanks were replaced. Also, the dump valves of the trains 'A' and 'B' feedwater heaters were replaced. The replacements were made in accordance with an engineering design document (PDC 98-38). After completing turbine trip testing at the end of the refueling outage, the plant returned to commercial service at 0354 hours on July 7th.

On August 5th, at approximately 0440 hours timeframe, the control room panel C2R alarm (A-2), "DRAIN TANK A LEVEL HI," occurred on three separate occasions (PR 99.1976). Licensed operator response identified that the drain tank T-103A dump valve LV-3002 was indicating a partially open position (OPEN and CLOSED) and that the T-103A drain valve LV-3001 was not fully open (OPEN and CLOSED position indication). On each occasion, the alarm cleared within 75 seconds or less, the alarm response procedure (ARP-C2R A-2) was reviewed, and main steam and feedwater parameters were monitored. A maintenance request (MR 19901770) had already been written to investigate/correct the problem.

On the next operator shift, on August 5th at 0935 hours, control room alarms C-2R (A-2), "DRAIN TANK A LEVEL HI," and C-1C (D-2), "3RD POINT HTR LEVEL LO," occurred. Licensed operator observation was as follows. The drain tank T-103A drain and dump valves were both indicating a dual position indication (OPEN and CLOSED), the feedwater train 'A' 3rd point heater water level was indicating a low water level and the heater's level controls were in manual control.

Licensed operator response to the alarms was in accordance with the respective alarm response procedure. The feedwater train 'A' 2nd point heater level controller, at panel C-4, was changed from automatic control to manual control. This action was taken in an attempt to fully open the heater's dump valve (LV-3141) and thereby, reduce the water level in drain tank T-103A. This action resulted in no change in the position indication (at Panel C-2) for dump valve LV-3002. The drain tank T-103A indications and train 'A' feedwater heaters' parameters were monitored. Maintenance (I&C) personnel were notified of the problem, and were dispatched to instrument rack C-81 (in the turbine building condensate demineralizers' area) where the drain tanks' level controllers are located.

Just prior to the event, plant operating conditions included the following:

The reactor was at 100 percent power with the reactor mode selector switch in the RUN position. The reactor vessel (RV) pressure was approximately 1036 psig with the water at the saturation temperature for that pressure. The RV water level was about +29 inches (narrow range level). The condensate pumps and feedwater pumps were in service with the feedwater level control system in the three element control mode.

The Core Standby Cooling Systems (HPCI, ADS, RHR/LPCI, and Core Spray) were operable. The Reactor Core Isolation Cooling System was operable. The ultimate heat sink, the Salt Service Water System, was operable, and the Reactor Building Closed Cooling Water System was operable, and the Reactor Building Closed Cooling Water System was operable.

The preferred offsite power source (345 kV transmission lines 342 and 355) was energized. The 345 kV switchyard ringbus was energized with ACBs 102, 103, 104 and 105 closed. The 4.16 kV auxiliary power distribution system (APDS) was energized from the Unit Auxiliary Transformer (UAT) with the bus fast transfer switches in the ON position. The secondary offsite power source (23 kV distribution system) was energized with the Shutdown Transformer in standby service. The station blackout diesel generator was in standby service.

The emergency diesel generators ('A' and 'B') were in standby service.

EVENT DESCRIPTION

On August 5, 1999, at 0946 hours, an automatic Reactor Protection System (RPS) scram signal and scram occurred while at 100 percent reactor power. The scram occurred as a result of an automatic trip of the main turbine.

The event was initiated by a sustained high water level condition in one (T-103A) of the four moisture separator drain tanks, and actuated the turbine master trip solenoid (MTS-1). The actuation of MTS-1 included the following responses:

- Loss of oil pressure to pressure switches (PS-37/38/39/40) that resulted in the scram signal that initiated the scram.

- Automatic closing of the turbine control valves, stop valves, and combined intermediate valves, and sequential opening of the three turbine steam bypass valves.

The reactor vessel/main steam pressure increased because the main steam flow exceeded the 25 percent total bypass capability of the bypass valves. The pressure increased from 1035 psig to 1111 psig in about 1.5 seconds, and resulted in the opening of all four of the Target Rock two-stage main steam relief valves for pressure relief as designed. The relief valves opened in the following sequence: RV-203-3C (pilot #1049) at about 1100 psig, RV-203-3A (pilot #1040) at about 1110 psig, RV-203-3B (pilot #1046) at about 1110 psig, and RV-203-3D (pilot #1208) at about 1110 psig. Relief valve 3A opened for about 7 seconds, 3B opened for about 4 seconds, 3C opened for about 4.5 seconds, and 3D opened briefly. The maximum steam pressure, about 1111 psig, occurred about 0.25 seconds after the first relief valve opened.

The responses initiated by MTS-1 resulted in the following responses:

- Automatic transfer of the 4.16 kV APDS buses (A1 through A6) from the UAT to the Startup Transformer.
- Automatic opening of the main generator field breaker.
- Automatic opening of switchyard ACBs 104 and 105.

Meanwhile, the RV water level decreased to about -18.7 inches due to the decrease in the void fraction in the RV water. The decrease to less than the low RV water level set-points (calibrated at about +12 inches) resulted in the automatic initiation of the Primary Containment Isolation Control System (PCIS) and Reactor Building Isolation Control System (RBIS).

The PCIS actuation resulted in the following designed responses:

- Automatic closing of the inboard and outboard Primary Containment System (PCS)/Reactor Water Sample isolation valves AO-220-44 and -45.
- Automatic closing of the inboard and outboard PCS Group 2/sample system isolation valves that were open.
- The PCS Group 3/Residual Heat Removal (RHR) System Shutdown Cooling suction piping isolation valves MO-1001-47 and -50 remained closed.
- The PCS Group 3/RHR System Low Pressure Coolant Injection mode valves MO-1001-29A/B remained closed.
- The PCS Group 6/Reactor Water Cleanup (RWCU) System isolation valves closed automatically.

The RBIS actuation resulted in the automatic start of the Standby Gas Treatment System (SGTS) trains 'A' and 'B', and automatic closing of the Reactor Building/Secondary Containment System (SCS) Trains 'A' and 'B' supply and exhaust ventilation dampers.

Initial Control Room operator response was orderly and included the following. The reactor mode selector switch was moved to the SHUTDOWN position in accordance with procedure 2.1.6, "Reactor Scram." EOP-01, "RPV Control," was entered because the RV water level was less than +12 inches. All control rods inserted into the reactor core. The position indication for eight control rods did not immediately indicate "full-in" (position 00) and the process computer "all rods in" flag was not initially received. While the operator at reactor control panel C-905 was in the process of selecting those individual control rods for position indication, the operator noted the "all rods in" flag was received. The verification was completed by 0948 hours.

By 0957 hours, the neutron monitoring system source range monitors (SRMs) 'A', 'B', and 'D' were inserted into the reactor core in accordance with procedure 2.1.6. SRM 'C' did not fully insert into the reactor core. [The cause was identified to be a blown fuse in the SRM 'C' drive circuitry. The fuse was replaced and SRM 'C' was inserted into the reactor core.]

At about 1005 hours, main stack isolation valve AO-3751 closed automatically. The valve closed because radiation monitors RM-1705-3A/B, that monitor main condenser off-gas activity, were downscale due to low offgas activity after the scram. The downscale condition of the monitors initiated the related time delay relay TDR-1705-23 (13 minutes). The control circuit's mode switch was moved from the MON2 (normal position) to the MON1 position in accordance with alarm response procedure ARP-CP600, and valve AO-3751 was opened at 1007 hours.

By 1014 hours, the reset of the RPS was completed.

EOP-04, "Secondary Containment Control," was entered at 1015 hours because the RWCU system backwash receiver tank room temperature was greater than 105 degrees Fahrenheit (EOP-04 entry condition).

After the RBIS and PCIS logic circuits were reset, the Reactor Building ventilation system was returned to normal service. EOP-04 was terminated at 1019 hours when the room temperature less than 105 degrees (after normal Reactor Building ventilation was restored).

The SGTS system was subsequently returned to standby service at about 1033 hours.

The RWCU System was returned to service at 1034 hours.

The RV water level was restored to the normal operating band (+20" to +30"), and EOP-01 was terminated by 1045 hours. Procedure 2.1.7, "Vessel Heatup and Cooldown," was initiated at that time.

By 1117 hours, procedure 2.1.6 was completed.

The mechanical disconnects located between the main transformer and switchyard were opened at about 1150 hours. Switchyard ACBs 104 and 105 were subsequently closed. The closing of the ACBs re-established the switchyard ringbus.

Problem Report 99.9448 was written to document the scram. The NRC Operations Center was notified in accordance with 10 CFR 50.72(b)(2)(iii) at 1245 hours on August 5th. A critique of the event was held on August 5th. The critique was held in accordance with procedure 1.3.63, "Conduct of Critiques and Incident Investigations." The critique was attended by applicable personnel including the licensed operators and I&C technicians who were on-shift and involved with the event.

A post trip review was conducted in accordance with procedure 1.3.37 (rev. 17), "Post-Trip Reviews." The procedure includes a check of various operational parameters and design aspects. Based on the review findings, the cause of the trip was known and in the process of correction, all safety-related and/or important equipment functioned properly, any malfunctioning equipment could be readily corrected, there were no Technical Specifications constraints to plant restart, and post trip parameter performance was within the Updated Final Safety Analysis and reload analysis. Therefore, the reactor was maintained in a hot shutdown condition, pending the completion of immediate corrective actions.

CAUSE

The direct cause of the scram was an automatic turbine trip while at 100 percent reactor power. The turbine trip was the consequence of a high water level condition in moisture separator tank T-102A for 10 seconds (designed time delay).

The cause of the high water level condition in the T-102A was due to a malfunction of drain tank T-103A level controller LC-3001 (drain valve LV-3001 controller) combined with incorrect settings on the drain tank's level controller LC-3002 (dump valve LV-3002 controller).

The root cause determined that a lack of knowledge in understanding how this type of moisture separator level controller operated existed in the Engineering and Maintenance disciplines. This lack of knowledge led to inappropriate changes to the associated calibration procedure and improper field adjustments to the controllers themselves resulting in the high water level condition.

CORRECTIVE ACTION

The following corrective action was taken prior to plant restart:

- The moisture separators' drain tanks' level controllers were functionally checked and inspected for degradation. Records of level controllers' calibration performed during RFO-12 were reviewed, analyzed, and compared to post trip data. This revealed that the output of the dump valves' level controllers would have limited the valves from opening fully. A calibration of the drain tanks' level transmitters was not possible because of steam and moisture present at the transmitters' buoyant force mechanisms.

- Walkdowns of the moisture separators' drain tanks' level controllers were performed. The focus of this action was to obtain as-found data for the tanks' drain and dump valves' controllers. The data included input/output relationships, indication for controller degradation, valve stroke times and operational checks for mechanical binding, indication for air regulator performance and checks for moisture in the air supply lines. All eight of the drain tanks' level controllers were replaced with in-kind pneumatic controllers (Fisher model 2506R/2516R).

Similar actions were taken for the feedwater heaters' level controllers and valves.

A reactor startup was initiated on 0509 hours on August 7th, and the unit returned to commercial service at 2312 hours. While at 50 percent reactor power, the feedwater heaters' control loops were tuned. Full reactor power was achieved at 1912 hours on August 9th. Data was collected at various power levels for the drain tanks' level controllers, and some tuning of the controllers was performed above 70 percent power to minimize drain tank level oscillations.

A planned reactor power reduction, from 100 percent to 74 percent, occurred on August 10th, for adjustment of the control rods' pattern. Full reactor power was subsequently achieved at 1932 hours. During the power reduction and subsequent power ascension, data on drain tank level control performance was obtained to ensure proper response.

ACTION TO PREVENT RECURRENCE

PNPS procedure 8.F.1, "Main Steam Instrumentation Calibration," was revised (Revision 13). The revision incorporated the lessons learned on the interaction of the moisture separators' and drain tanks' pneumatic controllers. Additionally, plant procedures that involved calibration of similar controllers were reviewed and revised to incorporate the lessons learned from this event.

Instrumentation & Calibration (I&C) technician training was updated to incorporate this event. The calibration of this type of controller was included as part of the continuing training program. The focus of this action was to practice the task of calibrating a pneumatic controller.

Engineering support personnel (ESP) training was conducted on controller theory and operation. This training included discussion on the controllers in use in the moisture separator with emphasis placed on how design changes can impact system response.

SAFETY CONSEQUENCES

This event posed no threat to public health and safety.

The neutron monitoring system includes the source range monitors (SRMs). During plant startup or shutdown evolutions, the SRMs function to automatically initiate the rod block circuitry to block the withdrawal of a control rod if SRM setpoint conditions occur. Technical Specification 3.2.C/Table 3.2.C-1 specifies a minimum of 3 operable SRMs for the rod block function. SRM 'C' failed to insert after the scram because of a blown fuse that affected the insertion of the SRM detector into the reactor core. SRMs 'A', 'B', and 'D' were operable and inserted into the core as designed. Therefore, the rod block function was not adversely affected by the failure of SRM 'C' to insert after the scram.

The turbine trip experienced during this event is bounded by the transient analysis described in the Updated Final Safety Analysis Report section 14.4.3, "Generator Load Rejection Without Bypass." The opening of some or all of the main Steam two-stage relief valves is an expected response to a turbine trip or load rejection with or without bypass at greater than about 45 percent power. For this event, relief valves RV-203-3A/B/C/D opened. The Technical Specification 3.6.D.1 setting for the main steam relief valves is 1095 to 1115 psig with a tolerance of +/- 11 psi. Therefore, the setpoint range of the relief valves including tolerance is 1084 psig to 1126 psig. The nameplate setpoint of the relief valves is 1115 psig. During the event, relief valves opened in a range of about 1100 to 1110 psig, and the highest RV dome pressure that occurred was about 1111 psig.

The Technical Specification 3.6.D.1 setting for the main steam safety valves is 1240 +/- 13 psi. During the event, the highest RV pressure that occurred (1111 psig) was less than the safety valves' setpoint of 1240 psig.

The turbine speed increased slightly as a result of the turbine trip but was less than the speed corresponding to the 109 percent overspeed trip setting (1972 - 1998 RPM) and the 112 percent backup overspeed trip setting (about 2016 RPM).

The decrease in the RV water level was the expected response to the scram and accompanying shrink in the RV water. The PCIS and RBIS actuations were the expected designed responses to a low RV water level condition (i.e., less than about +11.6 inches).

The Technical Specification Table 3.2.B trip setting for automatic actuation of the core standby cooling systems (CSCS) is -46.3 inches. During the event, the lowest reactor vessel water level that occurred, about -18.7 inches, was about 28 inches above the CSCS setpoint. In addition, the level was about 108 inches above the level (-127 inches) that corresponds to the top of the active fuel zone.

The lowest reactor vessel water level that occurred was about -18.7 inches. The level was greater than the setpoint, calibrated at about -46.3 inches, that initiates the anticipated transient without scram (ATWS) system functions for a recirculation pump trip (RPT) and alternate rod insertion (ARI). The highest reactor vessel pressure that occurred, 1111 psig, was less than the setpoint, calibrated at about 1175 psig, that initiates the ATWS system RPT and ARI functions and was less than the setpoint, calibrated at about 1400 psig, that initiates the ATWS function for a feedpump trip.

The highest reactor vessel pressure that occurred was 1111 psig and was an expected consequence of the turbine trip at 100 percent reactor power. The turbine trip resulted in the sequential opening of the turbine steam bypass valves. The valves have a combined bypass capacity of about 25 percent of the full power steam flow. The pressure was greater than the Technical Specification 3.1.1/Table 3.1.1 setting of less than about 1063 psig for the high reactor pressure scram function. The scram signal that initiated the scram, loss of turbine control oil pressure sensed by pressure switches PS-37/38/39/40, preceded the high reactor pressure scram signal.

The suppression pool water level and bulk water temperature was not affected as a result of the brief opening of the main steam relief valves.

REPORTABILITY

This report was submitted in accordance with 10 CFR 50.73(a)(2)(iv) because the actuation of the RPS, although an expected consequence of an automatic turbine trip at 100 percent reactor power, was not planned.

SIMILARITY TO PREVIOUS EVENTS

A review was conducted of Pilgrim Station Licensee Event Reports (LERs) submitted since 1984. The review focused on manual or automatic scrams resulting from a turbine trip due to a high moisture separator level condition. The review identified no similar reports. A review was also conducted of Pilgrim Station LERs or events prior to 1984 that involved a high moisture separator level condition. The review identified similar events that occurred on June 1, 1976, April 6, 1981, and April 9, 1982.

On June 1, 1976, at 2154 hours, an automatic turbine trip occurred at low power during startup from the 1976 refueling outage (RFO-2), shortly after the generator was phased to the 345 kV switchyard (at 2056 hours). The cause was a high water level in a moisture separator/drain tank.

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PILGRIM NUCLEAR POWER STATION	05000-293	1999	008	01	10 of 10

TEXT (If more space is required, use additional copies of NRC Form 366A) (17)

On April 6, 1981, at 1243 hours, an automatic scram (turbine stop valve closure) resulting from a turbine trip occurred while at 100 percent reactor power. The event occurred while troubleshooting a malfunction of the moisture separator drain tank T-103C drain valve LV-3006. During the troubleshooting, the tanks' dump valve (LV-3007) could not be opened before the turbine trip occurred.

On April 9, 1982, at 1424 hours, an automatic turbine trip occurred while at 23 percent reactor power. The turbine bypass valves operated as designed and the reactor remained at power. The cause of the trip was a high water level condition in moisture separator tank T-102C. The moisture separator/drain tank dump valve did not function properly because of blockage in the instrument air line to the tank's dump valve (LV-3007).

ENERGY INDUSTRY IDENTIFICATION SYSTEM (EIIS) CODES

The EIIS codes for this report are as follows:

COMPONENTS	CODES
Control, indicating, level (LIC)	LIC
Controller, level (LC)	MC
Control station, indicating, level (C-4)	LIK
Panel (C-2, C-4, C-81)	PL
Valve, level control (LV)	LCV

SYSTEMS	
Containment Isolation Control System (PCIS, RBIS)	JM
Engineered Safety Features Actuation System (PCIS, RBIS, RPS)	JE
Feedwater System	SJ
Main Steam System	SB
Main Turbine System	TA
Plant Protection System (RPS)	JC
Reactor Containment Building	NH
Reactor Water Cleanup (RWCU) System	CE
Standby Gas Treatment System (SGTS)	BH